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April 5, 2013

Ms. Rasha Allen
Air Permitting Section
Bureau of Air
Kansas Department of Health and Environment
1000 SW Jackson, Suite 310
Topeka, KS 66612-1366

Re: Response to Questions/Comments
Construction Permit Application for Naphtha Fractionation Project
Source ID No. 0150004 - Frontier El Dorado Refining LLC
El Dorado, Kansas

C-10961

Dear Ms. Allen:

Frontier El Dorado Refining LLC (FEDR) is submitting this letter in response to your question/comments in the March 11, 2013 email related to the Construction Permit Application for the Naphtha Fractionation Project (NFP). Per your request, FEDR understands that you need additional information to complete your review. The response to each of your requests is provided in the attachment. Each comment/question in your request is listed followed by FEDR's response in *"italics"*.

If you have any questions or comments regarding this submittal, please contact me at (316) 321-8478.

Sincerely,

Andrew Beard

Andrew Beard
Environmental Specialist

Enclosures

Frontier El Dorado Refining LLC
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Response to Questions/Comments
Construction Application for Naphtha Fractionation Project (NFP)

Sections 2 and 3

1. For fugitive components associated with the naphtha fractionation column, please explain what is meant by "net increase". Is it only added components or is it accounting for components removed as a result of removal of the Reformat Splitter and HTU3 Naphtha Splitter?

   Response: The fugitive components associated with the Naphtha Fractionation Column are estimated added components for project emissions estimating purposes since the project detailed design has not been finalized.

2. For the cooling tower, please explain why a controlled emission factor is used. A controlled emission factor can be used if there's a program ensuring the water pressure in heat exchangers is at least 35 kPa greater than VOC pressure in heat exchangers or a program monitoring for hydrocarbons in the water.

   Response: The cooling tower associated with the NFP will be Cooling Tower U-3601. This cooling tower is not subject to any program for ensuring the water pressure in heater exchangers is at least 35 kPa greater than VOC pressure in heat exchangers or a program monitoring for hydrocarbons in the water; therefore, the cooling tower's emission calculations have been updated to use the unmonitoring emission factor of 6 lb VOC/ 10^6 gal cooling water from Table 5.1-2 of US EPA's AP-42, dated January 1995. The project emissions in Table 1-1 of the application were also updated. The revised Tables1-1 and B-7 are provided in Attachment 1 of this response.

3. For the gasoline tanks, please explain:

   - Basis of 3,750 bpd (57.5 MMgal/yr) increase in throughput.

     Response: Currently benzene must be removed from gasoline to meet the latest applicable mandated benzene limit in gasoline for the refinery. As stated in Section 2.3.1 of the application, the Naphtha Fractionator will separate the feed streams into light naphtha, intermediate naphtha, and heavy naphtha. Light naphtha (benzene) will be converted to isomerate, intermediate naphtha (benzene precursors) will be directly sent to gasoline blending and not to the Reformers. Intermediate naphtha would generate benzene if sent to the Reformers. Therefore, the light and intermediate naphthas instead of being produced as benzene, will be converted to non-benzene materials and used toward gasoline production, as such, resulting in an increase in gasoline throughput.

- VOC emissions of 0.01 tpy in the text vs. 1.22 tpy from Tanks report.

  Response: *The VOC emissions of 0.01 tpy in the text was a typo. It should be 0.1 tpy. The calculated emissions from Tank 65 before and after the NFP are summarized in a table below. As presented in this table, the emissions from Rim Seal Loss and Deck Fitting are the same before and after the increase in throughput; therefore, the only emission increase in emissions from the throughput increase is Withdrawal Loss, which amounts to approximately 200.64 lbs, or 0.10 tpy. The tank reports are provided in Attachment 2 of this response. The results in tank calculations are slightly different from the previous tank run; however, this does not change the requested emission increase from Tank 65.*

Gasoline Tank Emission Increase Summary

Tank 65	Losses (lbs)					Losses (tpy)
	Rim Seal Loss	Withdrawal Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions	Total Emissions
Before	2,231	9.49	21.89	0	2261.98	1.13
After	2,231	210.13	21.89	0	2462.62	1.23
Increase	-	200.64	-	-	200.64	0.10

- If HAP emissions need to be accounted based on VOC emissions.

  Response: *The HAP content in gasoline is estimated to be approximately 40% by weight. Therefore, the increase in HAP emissions associated with the increase in gasoline throughput will be approximately 0.04 tons/year. This amount has been included in the revised Table 1-1 in Attachment 1 to this response.*

4. For the isomerate tanks,
   - Is throughput based on maximum isomerate stored?

     Response: *The throughout is based on maximum isomerate stored.*

   - Are HAPs not contained in isomerate?

     Response: *The HAP content in isomerate is estimated to be approximately 65% by weight. Therefore, the HAP emissions associated with the isomerate storage tank will be approximately 1.66 tons/year. This amount has been included in the revised Table 1-1 in Attachment 1 to this response.*

5. For the HGU-3 furnace,
   - Is it a natural draft process heater?

     <u>Response:</u> *Yes, the HGU-3 furnace is a natural draft heater (induced draft).*

   - Will natural gas, fuel gas, and PSA off-gas be combusted?

     <u>Response:</u> *The fuel to the HGU-3 furnace will normally be fuel gas and PSA off-gas. Fuel gas can also contain natural gas.*

   - Please explain the difference in design heat input rate from original permitting in May 2011.

     <u>Response:</u> *The furnace designed for the May 2011 permit was based on a Hydrogen Unit with a designed production rate of 32 million standard cubic feet per day (MMScfd), while the Hydrogen Unit associated with the NFP is designed for 17 MMScfd rounded up to 20 MMScfd.*

<u>Section 5</u>

6. For the HGU-3 furnace, it appears that the statement regarding project increases triggering PSD for CO is incorrect.

   <u>Response:</u> *The increase in CO emissions from the project is less than 100 tpy; therefore, the statement "The project increases trigger PSD for CO and CO_2e." in the first paragraph of Subsection 5.2.1 should be changed to "The project increase triggers PSD for CO_2e."*

7. Please explain the reference to the boiler in the section.

   <u>Response:</u> *The Hydrogen furnace also generates steam, and GHG emissions are generated by fuel combustion sources such as boilers, and heaters at the refinery. However, to avoid any confusion, an updated Section 5 is provided in Attachment 3 in which references to boiler, boilers, or the boiler have been removed or replaced where appropriate.*

8. The amortized installation costs were verified based on the information provided; however, it's not clear how the annualized cost was determined.

   <u>Response:</u> *The annualized cost was inadvertently included a hidden factor which should have been removed. A revised Table 5-3 is included at the end of the revised Section 5 in Item 7 above.*

Section 7

9. It's understood that equipment subject to MACT CC but also subject to Part 60 and/or Part 61 shall comply with MACT CC. However, please explain the reference made under NESHAP Subpart V: "FEDR will comply with the applicable requirements of Subpart V for any requirements that are deemed not exempted from Subpart CC."

   Response: The statement "...are deemed not exempted from Subpart CC" should be revised to "...are deemed not applicable to Subpart CC". NESHAP Subpart V requires that any leakage from surge control vessels and bottom receivers be equipped with a closed-vent system capable of capturing and transporting any leakage from the vessels back to the process or to a control device [40 CFR 61.242-9]. Although surge control vessels and bottoms receivers may not be considered piping components under MACT CC, they are listed under NESHAPS Subpart V. Surge control vessels and bottoms receivers are not listed under NSPS VV, NSPS VVa, NSPS GGG, or NSPS GGGa. Therefore, they are not subject to MACT CC; thus, they should remain subjecting to NESHAP Subpart V.

10. Based on the design heat-input rate of the furnace, K.A.R. 28-19-31(c) is not applicable.

   Response: We concur. The HGU3 furnace will have a maximum rated heat input less than 250 MMBtu/hr; therefore, K.A.R. 28-19-31(c) is not applicable to the furnace.

Appendix B

11. For the HGU-3 furnace,
    - Please provide manufacturer information, if available, verifying the CO emission factor of 0.04 lb/mmbtu.

      Response: The manufacturer's CO emission factor for the HGU-3 furnace is included in Attachment 4. This CO emission factor is lower than the 0.04 lb/MMBtu used in the application. However, FEDR wishes to use the 0.04 lb CO/MMBtu emission factor for conservative purpose.

    - It's not clear why worst-case emissions (fuel gas, flow, emission factors) are not determined for GHG.

      Response: The proposed GHG emission calculations have been updated to consider worst case for fuel gas, flow, and emission factors. The HHV used to calculate the fuel flow is assumed equal to 1020 Btu/scf, and the flow is updated to correspond with this HHV. The fuel carbon content and molecular weight used in the updated calculations also include a contingency factor. Equations C-5 and C-8 of 40 CFR §98.33 are used for the calculations. The CO_2 emission factor from Table C-1 of Part 98 Subpart C does not apply here since it can only be used for combustion sources with maximum rated heat input capacity of less than 30 mmBtu/hr per Note 2 of Table C-1 of Part 98 Subpart C, and 40 CFR §98.252(a)(2). The updated Table B-6 is provided in Attachment 5.

12. For HGU-3 fugitives (Table B-8),
    - Why are SOCMI factors used over refinery factors?

      Response: *The EPA allows for the use of SOCMI to calculate emissions from petroleum refineries. Please see the EPA's response to Question 500 of Section 4 of the 1998 EPCRA Section 313 Questions and Answers in Attachment 6 to this submittal.*

    - Please provide the basis for average VOC content of 7%.

      Response: *The average VOC content of 7% for HGU-3 is was calculated based on the average VOC content of all the streams with LDAR components within the HGU-3 unit. The calculations for VOC content for HGU-3 are included in Attachment 7.*

    - Relief valves are routed to flares; for other units, relief valves are not routed to flares?

      Response: *The design of HGU-3 has incorporated routing relief valves to the flares. However routing relief valves to flares is more difficult in existing units due to their current configuration, available spaces, etc.*

    - What factor in Table 2-5 is used for sample connections?

      Response: *Tables B-8 to B-12's footnote 1 should state "SOCMI Fugitive Emission Factors are from Table 2-1, except for factor for drains which come from Table 2-5".*

13. For the cooling tower and fugitives (Table 1-1 and Tables B-7 through B-12), emissions don't show CO_2e by accounting for the GWP of CH_4.

    Response: *The updated Table 1-1 in Attachment 1 shows CO_2e with GWP of CH_4 accounted for cooling tower and fugitives.*

14. For the HGU-3 atmospheric vent (Table B-13), please provide detailed calculations.

    Response: *Detailed calculations for HGU-3 Atmospheric Vents are included in Attachment 8. Table B-13 has also been updated to correct the hourly and annual emission rates.*

Attachment 1
Revised Cooling Tower VOC Emission Calculations
and Updated Table 1-1

Table B-7
Potential Increase in Emissions from Cooling Tower
Frontier El Dorado Refinery

$PM/PM_{10}/PM_{2.5}$ Emissions

Source Description	Tower - Increased Flow Capacity (gpm)	Drift Loss (%)	Drift Loss (gal/hr)	Total Liquid Drift Loss (lb drift/hr)	TDS Content (ppmw)	$PM/PM_{10}/PM_{2.5}$ Hourly Emissions[1] (lb/hr)	Operating Schedule (hrs/yr)	$PM/PM_{10}/PM_{2.5}$ Annual Emissions (tpy)
Cooling Tower	300	0.020%	3.6	30.0	910	0.027	8,760	0.12

1. $PM/PM_{10}/PM_{2.5}$ Hourly Emissions, lbs PM/hr = (TDS Content, ppm) / (1×10^6) x (Total Liquid Drift Loss, lbs drift/hr).
2. Drift Loss Rate based on default value in AP-42 Table 13.4-1 of 0.02% for Induced Draft Cooling Towers, Chapter 13.4 of AP-42, 1/95

VOC Emissions

Source Description	Tower - Increased Flow Capacity (gpm)	Fugitive Emission Factor ($lb/10^6$ gal)	Operating Schedule (hrs/yr)	VOC Emissions (lbs/hr)	Annual VOC Emissions (tpy)	CH_4 Emissions[2] (lbs/hr)	Annual CH_4 Emissions[2] (tpy)	Annual CO_2e Emissions (tpy)
Cooling Tower	300	6.0	8,760	0.108	0.473	0.027	0.12	2.48

1. Emission Factor based on Table 5.1-2, AP-42, 1/95.
2. Assumes that 25% of VOC leaks are CH_4

Table 1-1 Project Emissions Increases Compared to PSD Significance Levels

Source/ Source Category	Potential Emissions (tpy)											
	NO_x	SO_2	CO	VOC	PM	PM_{10}	$PM_{2.5}$	H_2SO Mist	H_2S	CO_2e	NH_3	HAPs
New HGU-3 Furnace	36.79	8.98	36.79	4.96	6.85	6.85	6.85	-	-	173,320	-	1.74
HGU-3 Fugitives	-	-	-	0.12	-	-	-	-	-	0.64	-	0.05
Crude Unit Fugitives (increase only)	-	-	-	7.61	-	-	-	-	-	39.94	-	3.04
Naphtha Fract. Tower Fugitives (net increase only)	-	-	-	1.31	-	-	-	-	-	6.89	-	0.52
ISOM Fugitives (increase only)	-	-	-	1.40	-	-	-	-	-	7.35	-	0.56
Gas Con Fugitives (increase only)	-	-	-	1.30	-					6.82		0.52
Cooling Tower (new)	-	-	-	0.47	0.12	0.12	0.12	-	-	2.48	-	-
Gasoline Tanks	-	-	-	0.10	-	-	-	-	-	-	-	0.04
Isomerate Tanks	-	-	-	2.55	-	-	-	-	-	-	-	1.66
HGU-3 Atmospheric Vent	-	-	-	0.39	-	-	-	-	-	-	0.20	-
HGU-3 Analyzer Vents	-	-	0.19	0.0004	-	-	-	-	-	2.08	-	-
Total Project Increases	**36.79**	**8.98**	**36.98**	**20.22**	**6.97**	**6.97**	**6.97**	**0**	**0**	**173,386**	**0.20**	**8.13**
PSD Significance Level	**40**	**40**	**100**	**40**	**25**	**15**	**10**	**7**	**10**	**75,000**	**N/A**	**N/A**
PSD/Netting Required (Y/N)	No	No	No	No	No	No	No	No	No	Yes	N/A	N/A

Attachment 2
TANKS 4.09d Runs for Tank 65

Before Project

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	65
City:	Wichita-Frontier El Dorado
State:	Kansas
Company:	Frontier El Dorado Refining Company
Type of Tank:	External Floating Roof Tank
Description:	U. Prem. A

Tank Dimensions

Diameter (ft):	60.00
Volume (gallons):	761,472.00
Turnovers:	3.57

Paint Characteristics

Internal Shell Condition:	Light Rust
Shell Color/Shade:	White/White
Shell Condition	Good

Roof Characteristics

Type:	Double Deck
Fitting Category	Detail

Tank Construction and Rim-Seal System

Construction:	Welded
Primary Seal:	Mechanical Shoe
Secondary Seal	Rim-mounted

Deck Fitting/Status	Quantity
Automatic Gauge Float Well/Bolted Cover, Gasketed	1

Meterological Data used in Emissions Calculations: Wichita-Frontier El Dorado, Kansas (Avg Atmospheric Pressure = 14.06 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

65 - External Floating Roof Tank
Wichita-Frontier El Dorado, Kansas

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
U. Prem. A	Jan	46.29	41.59	50.99	55.90	4.1794	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	Feb	46.82	41.81	51.83	55.90	4.2242	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	Mar	52.78	46.89	58.66	55.90	4.7647	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	Apr	58.88	52.51	66.26	55.90	5.3528	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	May	61.78	55.50	68.07	55.90	5.6572	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	Jun	65.40	59.05	71.75	55.90	6.0558	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	Jul	70.54	63.40	77.68	55.90	6.6607	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	Aug	69.40	62.79	76.01	55.90	6.5224	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	Sep	61.91	56.17	67.65	55.90	5.6704	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	Oct	58.49	52.70	64.28	55.90	5.3122	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	Nov	52.40	47.66	57.14	55.90	4.7196	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	Dec	48.31	44.20	52.42	55.90	4.3522	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

65 - External Floating Roof Tank
Wichita-Frontier El Dorado, Kansas

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Rim Seal Losses (lb):	145.1391	128.1804	181.8734	237.6410	187.5241	194.0246	255.2514	195.9200	194.8721	163.6589	176.1920	169.4221
Seal Factor A (lb-mole/ft-yr):	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000
Seal Factor B (lb-mole/ft-yr (mph)^n):	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Average Wind Speed (mph):	11.0000	9.4000	11.9000	13.6000	9.6000	9.0000	10.7000	8.1000	10.0000	9.0000	11.8000	12.4000
Seal-related Wind Speed Exponent:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Value of Vapor Pressure Function:	0.0880	0.0891	0.1028	0.1192	0.1280	0.1399	0.1591	0.1546	0.1284	0.1181	0.1019	0.0923
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	4.1794	4.2242	4.7547	5.3528	5.6972	6.0568	6.6607	6.5224	5.6704	5.3122	4.7196	4.3522
Tank Diameter (ft):	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000
Vapor Molecular Weight (lb/lb-mole):	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000
Product Factor:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Withdrawal Losses (lb):	0.7907	0.7907	0.7907	0.7907	0.7907	0.7907	0.7907	0.7907	0.7907	0.7907	0.7907	0.7907
Net Throughput (gal/mo.):	226,537.9200	226,537.9200	226,537.9200	226,537.9200	226,537.9200	226,537.9200	226,537.9200	226,537.9200	226,537.9200	226,537.9200	226,537.9200	226,537.9200
Shell Clingage Factor (bbl/1000 sqft):	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015
Average Organic Liquid Density (lb/gal):	6.2180	6.2180	6.2180	6.2180	6.2180	6.2180	6.2180	6.2180	6.2180	6.2180	6.2180	6.2180
Tank Diameter (ft):	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000
Roof Fitting Losses (lb):	1.3546	1.3720	1.5835	1.8361	1.9710	2.1547	2.4505	2.3810	1.8770	1.8164	1.5689	1.4220
Value of Vapor Pressure Function:	0.0880	0.0891	0.1028	0.1192	0.1280	0.1399	0.1591	0.1546	0.1284	0.1181	0.1019	0.0923
Vapor Molecular Weight (lb/lb-mole):	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000
Product Factor:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Tot. Roof Fitting Loss Fact.(lb-mole/yr):	2.8000	2.8000	2.8000	2.8000	2.8000	2.8000	2.8000	2.8000	2.8000	2.8000	2.8000	2.8000
Average Wind Speed (mph):	11.0000	9.4000	11.9000	13.6000	9.6000	9.0000	10.7000	8.1000	10.0000	9.0000	11.8000	12.4000
Total Losses (lb):	147.2844	130.3431	184.2475	240.2677	190.2857	196.9700	258.4925	199.0917	197.5398	166.2660	178.5516	171.6348

Roof Fitting/Status	Quantity	Roof Fitting Loss Factors KFa(lb-mole/yr)	Roof Fitting Loss Factors KFb(lb-mole/(yr mph^n))	m	Losses(lb)
Automatic Gauge Float Well/Bolted Cover, Gasketed	1	2.80	0.00	0.00	21.9265

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

65 - External Floating Roof Tank
Wichita-Frontier El Dorado, Kansas

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
U. Prem. A	2,230.60	9.49	21.89	0.00	2,261.97

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

After Project

Identification	
User Identification:	65
City:	Wichita-Frontier El Dorado
State:	Kansas
Company:	Frontier El Dorado Refining Company
Type of Tank:	External Floating Roof Tank
Description:	U. Prem. A
Tank Dimensions	
Diameter (ft):	60.00
Volume (gallons):	761,472.00
Turnovers:	79.07
Paint Characteristics	
Internal Shell Condition:	Light Rust
Shell Color/Shade:	White/White
Shell Condition	Good
Roof Characteristics	
Type:	Double Deck
Fitting Category	Detail
Tank Construction and Rim-Seal System	
Construction:	Welded
Primary Seal:	Mechanical Shoe
Secondary Seal	Rim-mounted

Deck Fitting/Status	Quantity
Automatic Gauge Float Well/Bolted Cover, Gasketed	1

Meterological Data used in Emissions Calculations: Wichita-Frontier El Dorado, Kansas (Avg Atmospheric Pressure = 14.06 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

65 - External Floating Roof Tank
Wichita-Frontier El Dorado, Kansas

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
U. Prem. A	Jan	46.25	41.59	50.99	55.90	4.1794	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	Feb	46.82	41.81	51.83	55.90	4.2242	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	Mar	52.78	46.89	58.63	55.90	4.7547	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	Apr	58.88	52.51	65.23	55.90	5.3525	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	May	61.78	55.50	68.07	55.90	5.6572	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	Jun	65.40	59.05	71.75	55.90	6.0555	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	Jul	70.54	63.40	77.68	55.90	6.6607	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	Aug	69.40	62.79	76.01	55.90	6.5224	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	Sep	61.91	56.17	67.65	55.90	5.6704	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	Oct	58.49	52.70	64.28	55.90	5.3122	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	Nov	52.40	47.66	57.14	55.90	4.7196	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3
U. Prem. A	Dec	48.31	44.20	52.42	55.90	4.3522	N/A	N/A	66.0000			94.00	Option 4: RVP=10.4, ASTM Slope=3.3

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

65 - External Floating Roof Tank
Wichita-Frontier El Dorado, Kansas

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Rim Seal Losses (lb):	145.1391	128.1804	181.8734	237.6410	187.5241	193.9246	256.2514	195.9260	194.8721	163.5599	176.1920	169.4221
Seal Factor A (lb-mole/ft-yr):	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000
Seal Factor B (lb-mole/ft-yr (mph)^n):	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000	0.4000
Average Wind Speed (mph):	11.0000	9.4000	11.9000	13.6000	9.6000	9.0000	10.7000	8.1000	10.0000	9.0000	11.6000	12.4000
Seal-related Wind Speed Exponent:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Value of Vapor Pressure Function:	0.0880	0.0891	0.1028	0.1192	0.1280	0.1399	0.1591	0.1546	0.1284	0.1181	0.1019	0.0923
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	4.1794	4.2242	4.7547	5.3528	5.6572	6.0556	6.6907	6.5224	5.6704	5.3122	4.7198	4.3522
Tank Diameter (ft):	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000
Vapor Molecular Weight (lb/lb-mole):	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000
Product Factor:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Withdrawal Losses (lb):	17.5110	17.5110	17.5110	17.5110	17.5110	17.5110	17.5110	17.5110	17.5110	17.5110	17.5110	17.5110
Net Throughput (gal/mo.):	5,017,162.9200	5,017,162.9200	5,017,162.9200	5,017,162.9200	5,017,162.9200	5,017,162.9200	5,017,162.9200	5,017,162.9200	5,017,162.9200	5,017,162.9200	5,017,162.9200	5,017,162.9200
Shell Clingage Factor (bbl/1000 sqft):	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015
Average Organic Liquid Density (lb/gal):	6.2180	6.2180	6.2180	6.2180	6.2180	6.2180	6.2180	6.2180	6.2180	6.2180	6.2180	6.2180
Tank Diameter (ft):	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000	60.0000
Roof Fitting Losses (lb):	1.3546	1.3720	1.5835	1.8361	1.9710	2.1547	2.4501	2.3808	1.9770	1.8184	1.5691	1.4221
Value of Vapor Pressure Function:	0.0880	0.0891	0.1028	0.1192	0.1280	0.1399	0.1591	0.1546	0.1284	0.1181	0.1019	0.0923
Vapor Molecular Weight (lb/lb-mole):	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000	66.0000
Product Factor:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Tot. Roof Fitting Loss Fact.(lb-mole/yr):	2.8000	2.8000	2.8000	2.8000	2.8000	2.8000	2.8000	2.8000	2.8000	2.8000	2.8000	2.8000
Average Wind Speed (mph):	11.0000	9.4000	11.9000	13.6000	9.6000	9.0000	10.7000	8.1000	10.0000	9.0000	11.6000	12.4000
Total Losses (lb):	164.0048	147.0634	200.9678	256.9881	207.0060	213.5903	276.2125	215.8178	214.3601	182.8893	195.2722	188.3552

Roof Fitting/Status	Quantity	Roof Fitting Loss Factors KFa(lb-mole/yr)	KFb(lb-mole/(yr mph^n))	m	Losses(lb)
Automatic Gauge Float Well/Bolted Cover, Gasketed	1	2.80	0.00	0.00	21.9265

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

65 - External Floating Roof Tank
Wichita-Frontier El Dorado, Kansas

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
U. Prem. A	2,230.60	210.13	21.89	0.00	2,462.62

Attachment 3
Updated Section 5 – BACT Review

SECTION 5
BACT REVIEW

5.1 Overview of Top-Down BACT

KAR 28-19-350, which refers to 40 CFR 52.21, requires that new and modified sources apply best available control technology (BACT) to control emissions for each regulated pollutant emitted from a major modification of an existing major stationary source located in an attainment area for that pollutant. The EPA endorses the Top-Down approach to BACT analysis. Under this approach, BACT is defined as the best control technology that is currently available as determined on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs of alternative control systems.

The five basic steps of Top-down procedure are:

Step 1 - Identify available control technologies;

Step 2 - Eliminate technically infeasible options;

Step 3 - Ranking Remaining Control Options Based on Effectiveness;

Step 4 - Evaluate Most Cost Effective Controls; and

Step 5 - Selection of BACT.

Step 1 - Identify All Available Control Technologies

The first step is to identify all "available" control options for each new or modified piece of equipment which triggers PSD for each pollutant under review. Available control options are those technologies or techniques with a practical potential for application to the equipment. During the course of the BACT analysis, one or more control options may be eliminated from consideration. However, at the outset, a comprehensive list must be compiled. This list should include potentially applicable Lowest Achievable Emission Rate (LAER) technologies, innovative technologies, and controls applied to similar source categories.

Step 2 – Eliminate Technically Infeasible Technologies

The second step of the top-down analysis is to arrange the comprehensive list, created in Step 1, based on technical feasibility. The technical evaluation should clearly document the difficulties based on source-specific factors and physical, chemical, and engineering principles that preclude the safe and successful use of the control option. Technically infeasible control technologies are removed from further evaluation.

Step 3 – Rank Remaining Control Options by Control Effectiveness

In the third step, all remaining control technologies are ranked by overall control effectiveness. Each control option and its control efficiency, expected emission rate, expected emission reduction, economic impacts, environmental impacts, and energy impacts is presented in this step.

Step 4 – Evaluate Most Effective Controls and Document Results

Based on the rank order developed in Step 3, the most effective control is evaluated based on its energy, environmental, and economic impacts. If the top control is eliminated as BACT, the next control option is selected and similarly evaluated. "This process continues until the technology under consideration cannot be eliminated by any source specific energy, environmental, or economic impacts which demonstrate that alternative to be inappropriate as BACT."

Step 5 – Select BACT

In this step, the most effective control not rejected in Step 4 is selected as BACT. If all control options are rejected as BACT, then no add-on control is considered BACT.

5.2 Detailed Top-Down BACT Analysis

5.2.1 BACT for HGU-3 Furnace – GHG BACT

This project includes the construction of a new furnace for the proposed hydrogen generation unit. The project increases trigger PSD for CO_2e. The following sub-sections present a review of BACT for this combustion unit for CO_2e emissions.

The new HGU-3 refomer furnace will be fired with refinery fuel gas and/or PSA purge gas. The combustion units will emit three GHGs: CH_4, CO_2, and N_2O. CO_2 will be emitted from these sources because it is a combustion product of any carbon-containing fuel. CH_4 will be emitted from these sources as a result of any incomplete combustion of refinery fuel gas. N_2O will be emitted from these sources in trace quantities due to partial oxidation of nitrogen in the air which is used as the oxygen source for the combustion process.

All fossil fuels contain significant amounts of carbon but the refinery fuel gas that will be combusted in the furnace is a low carbon fuel. One of the useful byproducts produced by the petroleum refining process is refinery fuel gas. This gas is generally similar to natural gas but contains less methane and more hydrogen and ethane than natural gas does. In the combustion of a fossil fuel, the fuel carbon is oxidized into CO and CO_2. Full oxidation of fuel carbon to CO_2 is desirable because CO has long been a regulated pollutant with established adverse environmental impacts, and because full combustion releases more useful energy within the process. In addition, emitted CO gradually oxidizes to CO_2 in the atmosphere.

The first step of the BACT analysis is to identify all available control technologies. The RBLC is a useful resource to identify any approved BACT determinations. Based on a December 2012 database query of permits issued after 2002 in the RBLC, there was one GHG BACT determination related to petroleum refineries, and it was for a steam methane reformer furnace similar to the HGU proposed in this project. There are three other RBLC GHG BACT determinations for power plants (RBLC IDs: VT-0037, IA-0101) and a fertilizer manufacturer (RBLC ID: IA-105). Good combustion practices and energy efficiency are BACT as identified by these entries.

Given that there is relatively little case-specific GHG information due to the recent start of the GHG program, other published EPA GHG BACT guidance will be referenced. EPA has released the following documents that were used to identify potential control technologies and work practices:

- Energy Efficiency Improvement and Cost Saving Opportunities for Petroleum Refineries: An ENERGY STAR Guide for Energy Plant Managers. Document Number LBNL-56183, February 2005;
- Available and Emerging Technologies for Reducing Green House Gas (GHG) emissions from the Petroleum Refining Industry, EPA, October 2010;
- Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers, EPA, October 2010; and
- EPA's GHG Mitigation Database was accessed several times during the permit application update in October 2012. However, the system was inoperable during that time with a message "The requested resource (/GHGMDB/) is not available."

A BACT analysis for CO_2 emissions is presented in the following steps.

5.2.1.1 *Step 1 – Identification of CO_2 Control Technologies*

The following technologies were identified as CO_2 control options for the new combustion unit based on available information and data sources:

- Use of Low Carbon Fuels;
- Use of Good Combustion Practices;
- Energy Efficient Design;
- Pre-Combustion Carbon Capture and Storage (CCS); and
- Post-Combustion CCS.

5.2.1.1.1 Low Carbon Fuels

Table 5-1 in this section presents the amount of CO_2 formed when combusting fossil fuels, including some of the fuels that will be used by the new combustion unit.

Table 5-1 CO_2 Emission Factors[1]

Fuel Type	Default CO_2 Emission Factor
Coal and coke	kg CO_2/mmBtu
Anthracite	103.54
Bituminous	93.40
Subbituminous	97.02
Lignite	96.36
Coke	102.04
Natural gas	kg CO_2/mmBtu
(Weighted U.S. Average)	53.02
Distillate Fuel Oil No. 1	73.25
Distillate Fuel Oil No. 2	73.96
Distillate Fuel Oil No. 4	75.04
Residual Fuel Oil No. 5	72.93
Residual Fuel Oil No. 6	75.10
Used Oil	74.00
Kerosene	75.20
Liquefied petroleum gases (LPG)	62.98
Propane	61.46
Propylene	65.95
Ethane	62.64
Ethanol	68.44
Ethylene	67.43
Isobutane	64.91
Isobutylene	67.74
Butane	65.15
Butylene	67.73
Natural Gasoline	66.83
Other Oil (>401 deg F)	76.22
Pentanes Plus	70.02
Petrochemical Feedstocks	70.97
Petroleum Coke	102.41

Fuel Type	Default CO_2 Emission Factor
Special Naphtha	72.34
Unfinished Oils	74.49
Heavy Gas Oils	74.92
Lubricants	74.27
Motor Gasoline	70.22
Aviation Gasoline	69.25
Kerosene-Type Jet Fuel	72.22
Asphalt and Road Oil	75.36
Other fuels-solid	kg CO_2/mmBtu
Municipal Solid Waste	90.7
Tires	85.97
Plastics	75.00
Petroleum Coke	102.41
Other fuels—gaseous	kg CO_2/mmBtu
Blast Furnace Gas	274.32
Coke Oven Gas	46.85
Propane Gas	61.46
Fuel Gas	**59.00**

Fuel Type	Default CO_2 Emission Factor
Biomass fuels—solid	kg CO_2/mmBtu
Wood and Wood Residuals	93.80
Agricultural Byproducts	118.17
Peat	111.84
Solid Byproducts	105.51
Biomass fuels—gaseous	kg CO_2/mmBtu
Biogas (Captured methane)	52.07
Biomass Fuels—Liquid	kg CO_2/mmBtu
Ethanol	68.44
Biodiesel	73.84
Biodiesel (100%)	73.84
Rendered Animal Fat	71.06
Vegetable Oil	81.55

[1] *Obtained from 40CFR98, Subpart C, Table C-1*

As shown in the table above, the use of natural gas and refinery fuel gas reduces the production of CO_2 from combustion of fuel relative to burning solid fuels (e.g. coal or coke) and liquid fuels (i.e., distillate or residual oils).

5.2.1.1.2 Good Combustion Practices

Good combustion practices for process heaters fired with refinery fuel gas include the following:

- Good air/fuel mixing in the combustion zone;
- Sufficient residence time to complete combustion;
- Proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality;
- Good burner maintenance and operation;
- High temperatures and low oxygen levels in the primary combustion zone;
- Monitor oxygen levels and air intake to optimize the fuel/air ratio and minimize excess air;
- Implementing a maintenance program to monitor fouling conditions in the subject combustion units; and

- Conduct a thermal tune-up annually. The tune-up will consist of inspection of the burner, flame pattern, and air-to-fuel ratio.

5.2.1.1.3 Energy Efficient Design

When possible, the use of the following can provide an energy efficient design to minimize the required fuel combustion for process heaters.

- Combustion Air Preheat;
- Process Integration and Heat Recovery;
- Use newer burner with latest proven engineering design; and
- Excess Combustion Air Monitoring and Control.

5.2.1.1.4 Pre-Combustion or Post-Combustion Carbon Capture and Storage (CCS)

As referenced in the March 2010 GHG Title V and PSD permitting guidance (Document No. EPA457/B11-001), EPA has identified CCS as an available add-on control technology that must be evaluated as if it were technically feasible.

Pre-combustion carbon capture for fuel gas combustion involves substituting pure oxygen for air in the combustion process, resulting in a concentrated CO_2 exhaust stream so it may be captured more effectively. The oxygen may be isolated from air using a number of technologies, including cryogenic separation and membrane separation. Post-combustion carbon capture for fuel gas combustion is applied to conventional combustion techniques using air and carbon-containing fuels in order to isolate CO_2 from the combustion exhaust gases. There are a number of methods and processes that could be used to capture CO_2 from the dilute exhaust gases produced by the new combustion units. These capture technologies include separation with solvent or physical filters, cryogenic separation to condense the CO_2, and membrane separation technologies. In addition, the CCS technology is also comprised of the distinct stages below:

- Pressurization of the captured CO_2;
- Transmission of CO_2 via pipeline; and
- Injection and long term storage of the captured CO_2.

In order to provide effective reduction of CO_2 emissions, efficient methods of compression, transport, and storage would also be required. This would require transporting the captured CO_2 to a suitable geological storage formation including the following:

- Depleted oil and gas reservoirs;
- Unmineable coal seams;
- Saline formations;

- Basalt formations; and
- Terrestrial ecosystems.

There are several major unresolved issues with respect to CO_2 sequestration including the legal process for closing and remediating sequestration sites and liability for accidental releases from these sites.

5.2.1.2 *Step 1 - CH_4 and N_2O Control Technologies*

The following technologies were identified as CH_4 and N_2O control options for the new combustion units based on available information and data sources.

- Use of low carbon fuels;
- Use of good combustion practices;
- Energy efficient design; and
- Oxidation catalysts (CH4 Control Only).

5.2.1.2.1 Low Carbon Fuels

The following table presents the default emission factors of CH_4 and/or N_2O formed when combusting fossil fuels, including some of the fuels that will be used by the new combustion units.

Table 5-2 CH_4 and N_2O Emission Factors[2]

Fuel type	Default N_2O emission factor (kg CH_4/mmBtu)	Default CH_4 emission factor (kg CH_4/mmBtu)
Coal and Coke (All fuel types in Table C–1)	1.6×10^{-03}	1.1×10^{-02}
Natural Gas	1.0×10^{-04}	1.0×10^{-03}
Petroleum (All fuel types in Table C–1)	6.0×10^{-04}	3.0×10^{-03}
Municipal Solid Waste	4.2×10^{-03}	3.2×10^{-02}
Tires	4.2×10^{-03}	3.2×10^{-02}
Blast Furnace Gas	1.0×10^{-04}	2.2×10^{-05}
Coke Oven Gas	1.0×10^{-04}	4.8×10^{-04}
Biomass Fuels—Solid (All fuel types in Table C–1)	4.2×10^{-03}	3.2×10^{-02}
Biogas	6.3×10^{-04}	3.2×10^{-03}
Biomass Fuels—Liquid (All fuel types in Table C–1)	1.1×10^{-04}	1.1×10^{-03}

[2] *Obtained from 40CFR98, Subpart C, Table C-2.*

As shown in the table, the use of natural gas and refinery fuel gas reduces the production of CH_4 and N_2O from combustion of fuel relative to burning solid fuels (e.g. coal or coke) and liquid fuels (i.e., distillate or residual oils).

5.2.1.2.2 Good Combustion Practices

Good combustion practices for the new combustion units fired with refinery fuel gas include the following:

- Good air/fuel mixing in the combustion zone;
- Sufficient residence time to complete combustion;
- Proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality;
- Good burner maintenance and operation;
- High temperatures and low oxygen levels in the primary combustion zone;
- Monitor oxygen levels and air intake to optimize the fuel/air ratio and minimize excess air;
- Implementing a maintenance program to monitor fouling conditions in the subject combustion unit; and
- Conduct a thermal tune-up annually. The tune-up will consist of inspection of the burner, flame pattern, and air-to-fuel ratio.

5.2.1.2.3 Energy Efficient Design

When possible, the use of the following can provide an energy efficient design for the new combustion units minimizing the required fuel combustion for process heat.

- Combustion Air Preheat;
- Process Integration and Heat Recovery;
- Use newer burner with latest proven engineering design; and
- Excess Combustion Air Monitoring and Control.

5.2.1.2.4 Oxidation Catalysts

Oxidation catalyst has been widely applied as a control technology for CO and VOC emissions from natural gas-fired combined cycle gas turbines and would also provide reduction in CH_4 emissions. This technology utilizes excess air present in the combustion exhaust and the activation energy required for the reaction to lower CH_4 concentration in the presence of a catalyst. The optimum temperature range for these systems is approximately 850°F to 1,100°F. No chemical reagent addition is required.

5.2.1.3 *Step 2 – Eliminate Technically Infeasible Options*

This step of the top-down BACT analysis eliminates any control technology that is not considered technically feasible unless it is both available and applicable.

5.2.1.3.1 Carbon Capture and Storage – Technically Infeasible

The pre-combustion technique for CO_2 separation involves substituting pure oxygen for air in the combustion process, resulting in a concentrated CO_2 exhaust stream. This "oxyfuel" process has not yet been tested or demonstrated in a project such as the new combustion units at the refinery. However, for purposes of BACT analysis, it is assumed that this technology would be technically feasible since it is both available and applicable.

There are a number of methods and processes that could be used to capture CO_2 from the dilute exhaust gases produced by the new combustion units. These capture technologies include separation with solvent or physical filters, cryogenic separation to condense the CO_2, and membrane separation technologies.

5.2.1.3.1.1 Separation with Solvent Scrubbers – Technically Infeasible

There are many solvents under development for the separation of CO_2 from combustion of flue gases through chemical absorption. The most commercially developed of these processes use monoethanolamine (MEA) as the solvent. MEA has the advantage of fast reaction with CO_2 at low partial pressure. The primary concern with MEA is corrosion in the presence of O_2 and other impurities, high solvent degradation rates due to reactions with SO_2 and NO_X, and the energy requirements for solvent regeneration.

Diethanolamine (DEA) is another solvent available for CO_2 removal. While some research shows that slightly lower CO_2 overheads can be achieved with DEA relative to MEA, the same problems with corrosion and high degradation rates exist, in addition to foaming tendencies. Another commercially available solvent is methyldiethanolamine (MDEA), which offers advantages over MEA and DEA, such as low corrosion, slow degradation rates, low amine reboiler duty, reduced solvent losses, and low circulation demand. However, its slow reaction rate for CO_2 makes it impractical when removal of large amounts of CO_2 is desired, such as with the new combustion units in this application. Therefore, FEDR does not believe using solvent scrubbing with MEA, DEA or MDEA is a technically feasible technology for this application.

Solvent scrubbing has been used in the chemical industry for separation of CO_2 in exhaust streams and is a technically feasible technology for this application; however, it has not been demonstrated in large scale industrial process applications.

5.2.1.3.1.2 Cryogenic Separation – Technically Infeasible

The cryogenic CO_2 capture process includes the following steps:

- Dry and cool the combustion flue gas;
- Compress the flue gas;
- Further cool the compressed flue gas by expansion which precipitates the CO_2 as a solid;
- Pressurize the CO_2 to a liquid; and
- Reheat the CO_2 and remaining flue gas by cooling the incoming flue gases.

The final result is the CO_2 in a liquid phase and a gaseous nitrogen stream that can be vented through a gas turbine for power generation. The CO_2 capture efficiency depends primarily on the pressure and temperature at the end of the expansion process. However, this process has not been commercially demonstrated on gas streams with low CO_2 concentrations such as the new combustion units at the petroleum refinery. To date there is insufficient data available to accurately complete cost analyses for this developmental technology.

5.2.1.3.1.3 Membrane Separation – Technically Infeasible

This method is commonly used for CO_2 removal from natural gas at high pressure and high CO_2 concentration. Membrane-based capture uses permeable or semi-permeable materials that allow for selective transport/separation of CO_2 from flue gas. It has been estimated that 80 percent of the CO_2 could be captured using this technology. The captured CO_2 would then be purified and compressed for transport. Membrane technology is not fully developed for CO_2 concentration and gas flow to process heaters at a petroleum refinery. To date there is insufficient data available to accurately complete cost analyses for this developmental technology.

5.2.1.3.1.4 Carbon Transport and Storage Separation – Technically Infeasible

There are available technically feasible methods for compression, transport, and storage of concentrated CO_2 streams. Options for capturing emissions from the new combustion units fired with refinery fuel gas, which would be required as an element of CCS as a GHG emission control option, were discussed in the preceding three subsections under carbon capture and storage.

5.2.1.3.1.5 Oxidation Catalysts – Technically Infeasible

Oxidation catalysts are not technically feasible. The typical oxidation catalyst for CH_4-containing exhaust gases is rhodium or platinum (noble metal) catalyst on an alumina support material. This catalyst is installed in an enlarged duct or reactor with flue gas inlet and outlet distribution plates. Acceptable catalyst operating temperatures range from 400 to 1250 °F, with the optimal range being 850 to 1,100 °F. Below approximately 600 °F, a greater catalyst volume would be required to achieve the same reductions. To achieve this temperature range in process heaters fired with refinery fuel gas, the catalyst would need to be installed in the heater upstream of any waste heat recovery or air preheat equipment.

Installation of oxidation catalyst in flue gas containing more than trace levels of SO_2 will result in poisoning and deactivation of the catalyst by sulfur-containing compounds, as well as increasing the conversion for SO_2 to SO_3. The increased conversion of SO_2 to SO_3 will increase condensable particulate matter emissions and increase flue gas system corrosion rates. For these reasons, catalytic oxidation of CH_4 is not considered technically feasible for the refinery fuel gas fired process heater.

5.2.1.3.1.6 Lower Carbon Fuels – Technically Infeasible

The new combustion units will combust refinery fuel gas and PSA off-gas which are low-carbon fuels. The only identified fuels with lower CO_2 formation rates are syngas, pressure swing adsorption ("PSA") tail gas, and natural gas. Production of additional syngas or PSA tail gas would lead to overall increases in GHG emissions from the refinery and do not represent options for reducing GHG emission. Natural gas is commercially available and would yield slightly reduced CO_2 emission rates from the new combustion units, but displacing refinery fuel gas from use as fuel in the new combustion units would necessitate disposal of this fuel gas by combustion elsewhere at the refinery, such as by flaring, which would increase overall CO_2 emissions from the site. Thus there are no control options involving the use of lower carbon fuels in the new combustion unit that is technically feasible for reducing GHG emissions relative to the proposed use of refinery fuel gas, and available PSA purge gas.

5.2.1.3.1.7 Good Combustion Practices – Technically Feasible

Good combustion practices for process heaters fired with refinery fuel gas are technically feasible and are inherent in the design of the new combustion units.

5.2.1.4 *Step 3 – Rank Remaining Control Technologies*

The following technologies and control efficiencies were identified as technically feasible for CO_2 control options for process heaters based on available information and data sources:

- Post-Combustion CCS (assumed 93% control efficiency);
- Pre-Combustion CCS (assumed 87% control efficiency);
- Use of low carbon fuels (control efficiency is not applicable);
- Use of good combustion practices (efficiency is not applicable); and
- Energy efficient design (efficiency is not applicable).

5.2.1.5 *Step 4 – Evaluate the Most Effective Controls and Document Results*

5.2.1.5.1 Use of Low Carbon Fuels, Good Combustion Practices and Energy Efficient Design

The use of low carbon fuels and good combustion practices are inherent in the design and operation of the new combustion units associated with this project. Good combustion practices are identified as GHG BACT for other issued PSD projects (RBLC IDs: IA-0105, IA-0101).

Continuously monitored indicators will be used to ensure that the new combustion units will operate within optimum design parameters. These parameters include: fuel flow and stack O_2 and temperature. Annual tune-ups for thermal efficiency as a work practice standard will be conducted. Other energy efficient designs will be incorporated as feasible, depending on the process heater's configuration; specifically, the use of Combustion Air Preheat, Process Heat to Generate Steam, Process Integration and Heat Recovery, and Excess Combustion Air Monitoring and Control. Energy efficiency is identified as GHG BACT for other issued PSD projects (RBLC IDs: VT-0037).

In addition, the new combustion units will be operated according to the manufacturer's specifications and monitoring will be consistent with the site's GHG monitoring plan required by 40 CFR Part 98.

5.2.1.5.2 Carbon Capture Systems

5.2.1.5.2.1 Post-Combustion Carbon Capture

For the purposes of the following analysis of CCS, chemical absorption using MEA based solvents is assumed to represent the best post-combustion CO_2 capture option. This capture efficiency is assumed to be 93 percent effective. The CO_2 emissions from the new combustion units are estimated to be 173,386 tons per year. The CO_2

rich solvent from the scrubber would then be pumped to a regeneration system for CO_2 removal and reuse. The CO_2 would need to be dried, compressed from low pressure up to 2,000 psi and transported by pipeline to the nearest pipeline that would conceivably use the supply for Anadarko pipeline approximately 90 miles away. This scenario provides a lower cost estimate than assuming direct transportation to the nearest storage reservoir, the Teapot Dome Field near Casper, Wyoming, located approximately 800 miles away from FEDR. The costs would be substantially higher due to more pipeline transport and the added costs of storage.

The estimated increase in capital costs for the CCS equipment needed for capture and compression would be up to approximately 80 percent[2] for a grass root facility. As stated in subsection 4.2.5.2.1, the costs are expected to be higher at a modified facility due to issues associated with pre-existing piping and infrastructure issues. Pipeline transportation and injection/storage are estimated to be \$1.5 - \$23 per tonne CO_2 (equivalent to \$1.36 to \$20.86 per US ton) and are highly dependent on distance to nearest available carbon storage facility, terrain the pipeline must pass through, type of storage reservoir, existing infrastructure, regional factors, etc. In addition, adding the CCS would result in an appreciable energy penalty simply because the CCS process will use energy produced by the plant resulting in a loss of efficiency which may in turn potentially increase the natural gas fuel use of the plant to overcome these efficiency losses.

In this submittal, the costs associated with pipeline transport of CO_2 post-capture are estimated using the March 2010 National Energy Technology Laboratory (NETL) document "Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs DOE/NETL-2010/1447"[3]. The calculations of estimated costs associated with materials, labor, indirect costs and right of way acquisition were based on functions of pipeline diameters and lengths that were determined as appropriate for the site. Additional costs associated with compression, amine scrubbing, surge protection and pipeline control were taken directly from the NETL document. The nearest CO_2 delivery line to the refinery is a pipeline operated by Anadarko Petroleum, located approximately 90 miles away. Assuming the Anadarko Pipeline could receive effluent from FEDR's amine system and use it to support EOR, the cost per short ton CO_2 removed is estimated at over \$254.42 /ton and the total cost is estimated to be over \$267 MM. This cost exceeds the capital cost of the new combustion units.

In order for the pipeline to accept scrubbed CO_2 from the new combustion units the effluent stream would have to be further concentrated and pressurized, corresponding to more equipment in addition to the amine unit, cryogenic unit and dehydration unit needed for necessary separation. Unlike a natural gas plant set up to separate and compress CO_2, the refinery does not currently have a system for CO_2 separation. Therefore, additional site-specific energy consumption for CO_2 separation and

[2] "Report of the Interagency Task Force on Carbon Capture and Storage", August 2010, pg 33 (http://www.epa.gov/climatechange/policy/ccs_task_force.html)

[3] "Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs DOE/NETL-2010/1447", The US Department of Energy and National Energy Technology Laboratory, 2010.

compression would need to be taken into considerations for CCS implementation. It is likely that this additional energy consumption will affect the CO_2 efficiency from the new combustion units.

Due to the extraordinary costs of implementing CCS at the refinery, it is considered a technically infeasible and economically unreasonable control option, and is not selected in the 5-step top down BACT analysis. See Table 5-3 at the end of this section for a detailed breakdown of the estimated costs.

These adverse energy, environmental, and economic impacts are significant and outweigh the environmental benefit of CCS. Therefore, CCS does not represent BACT for the new combustion unit associated with this project.

5.2.1.5.2.2 Carbon Transport and Storage

In addition to the adverse economic impacts that show CCS is not a viable option for this project, the use of CCS for new combustion units would entail significant adverse energy and environmental impacts due to increased fuel usage in order to meet the steam and electric load requirements of these systems. In order to capture, dry, compress, and transport to a suitable enhanced oil recovery (EOR) site, the CO_2 available for capture from the new combustion unit would require excessive amounts of additional electric power and steam generation capacity. The generation of the steam and electric power required by the project would itself result in GHG emissions, which would offset some if not all of the net GHG reduction achieved by capturing and storing the CO_2 emitted by the new combustion unit.

5.2.1.6 *Step 2 – Selection of BACT*

The use of CO_2 capture at FEDR would entail significant adverse energy and environmental impacts due to increased fuel usage in order to meet the steam and electric load requirements of these systems. In addition to the adverse impacts from steam and electricity generation that will be needed, the capital cost of the equipment to capture, dry, compress, and transport CO_2 make it economically infeasible. The adverse energy, environmental, and economic impacts are significant and outweigh the environmental benefit of CO_2 capture for this project and does not represent BACT for the new combustion unit.

FEDR will incorporate the use of low carbon fuels (refinery fuel gas and/or natural gas), good combustion practices, and energy efficient design where possible for the new combustion unit to meet BACT.

5.2.2 BACT For Fugitive Emissions

Fugitive leaks from new piping and process fugitive components may contain a percentage of CH_4 emissions and, as such, are a source of GHG associated with the project. BACT for the CH_4 emissions from fugitive emissions is evaluated as follows, though at less than 0.05% of the total hydrogen plant's GHG emissions, the total estimated fugitive CH_4 emissions as CO_2e are predicted to have a very negligible contribution to the plant's total GHG emissions.

5.2.2.1 *Step 1 – Identify All Potential Control Technologies*

It is infeasible to capture GHG emissions from fugitive sources. Therefore, CCS is not an add-on control technology that has a potential for application and it is not identified as a feasible technology for controlling fugitives. However, fugitive GHG can be reduced by utilizing a leak detection and repair (LDAR) program.

The potential control practices and technologies for process fugitive emissions of CO2e are based on compliance with the EPA Refinery MACT LDAR program. Although LDAR is currently only required for VOC (and not methane) sources, an acceptable LDAR program will indirectly minimize GHG fugitive emissions. Specifically, the implementation of an LDAR program will:

- Identify and repair any VOC-related leaks will result in a reduction of GHG emissions from these piping components.
- Require use of equipment designs that result in minimal VOC (and thus GHG) fugitive emissions.

5.2.2.2 *Step 2 – Eliminate Technically Infeasible Options*

All of the technologies listed in Step 1 except CCS are technically feasible.

5.2.2.3 *Step 3 – Ranking of Remaining Control Technologies by Control Effectiveness*

FEDR intends to implement all technologies listed in Step 1. The most effective identified control strategy for GHG emissions from equipment leaks is compliance with the EPA for Refinery MACT, which will not result in any adverse energy or environmental impacts.

The components associated with the new combustion units will be subject to the EPA Refinery MACT LDAR program which has specific leak definitions and monitoring requirements. Therefore, an LDAR program complying with Refinery MACT for fugitive components is proposed as BACT and constitutes the most stringent LDAR applicable option.

5.2.2.4 *Step 4 – Economic Evaluation of Ranked Controls*

FEDR intends to implement the EPA's Refinery MACT LDAR program to minimize fugitive GHG emissions via identification and repair of leaks and implementation of compliant equipment design standards. Therefore, an economic evaluation is not required to reject any potential control technologies.

5.2.2.5 *Step 5 – Selection of GHG BACT for Fugitives*

FEDR proposes that implementing the EPA's Refinery MACT LDAR program constitutes BACT for CO_2e emissions from the new combustion units.

Table 5-3
Estimated Cost for CCS of Stack CO_2 Emissions
Frontier El Dorado Refinery

CO_2 Pipeline Data

Pipeline Length	90 miles	to Andarko CO_2 Pipeline
Pipeline Diameter	6 inches	
Number of Injection Wells		
Short Ton of CO_2	173,386.48 tons/yr	
Captured Short Ton of CO_2	161,249 tons/yr	

CCS Cost Breakdown

Cost Type	Units	Cost		
Pipeline Costs				
Pipeline Materials	\$ Diameter (inches), Length (miles)	$64,632 + $1.85 x L x (330.5 x D^2 + 686.7 x D + 26,920)	\$	7,213,842.30
Pipeline Labor	\$ Diameter (inches), Length (miles)	$341,627 + $1.85 x L x (343.2 x D^2 + 2,074 x D + 170,013)	\$	32,777,858.30
Pipeline Miscellaneous	\$ Diameter (inches), Length (miles)	$150,166 + $1.58 x L x (8,417 x D + 7,234)	\$	8,360,225.20
Pipeline Right of Way	\$ Diameter (inches), Length (miles)	$48,037 + $1.20 x L x (577 x D + 29,788)	\$	3,639,037.00
Other Capital				
Compression	\$	14,000,000	\$	14,000,000.00
Amine Unit	\$	200,000,000	\$	200,000,000.00
CO_2 Surge Tank	\$	1,150,636	\$	1,150,636.00
Pipeline Control System	\$	110,632	\$	110,632.00
O&M				
Fixed O&M	\$/mile/year	8,632	\$	8,632
		Total Pipeline Cost =	\$	267,260,862.80

Amortized Cost

Total Capital Investment (TCI) =			\$	267,260,862.80
Capital Recovery Factor (CRF) = $i(1+i)^n/((1+n)^n - 1)$				0.15
i = interest rate =	0.08			
n = equipment life =	10	years		
		Amortized Installation Costs = CRF*TCI =	\$	39,829,749.73

Total Pipeline Annualized Cost	\$	41,024,642.22
Cost per short ton CO_2	\$	254.42

Attachment 4
Manufacturer's CO Emission Factor

From:	Leigh, Donald R.
To:	Hittle, Kane E.; Beard, Andrew S.
Subject:	Fwd: H2 Plant Bid
Date:	Thursday, March 14, 2013 5:30:08 PM

Begin forwarded message:

From: Sara Cosper <SCosper@technip.com>
Date: March 14, 2013, 5:11:38 PM CDT
To: "Leigh, Donald R" <DLeigh@Frontieroil-eld.com>
Cc: Vinay Khurana <VKhurana@technip.com>, Abhijeet Karnik <AKarnik@technip.com>
Subject: Re: Fw: H2 Plant Bid

Don:

Please see our responses to your questions.

1) Fired duty for the reformer - 179.61 MMBtu/h (LHV), 199.9 MMBtu/h(HHV)

2) NOx per year (tons) - 26.3 tons (short) per year
(0.03lb/MMBtu x 199.9 MMBtu/h x 24 hours/day x 365 days/year)/2000

3) CO per year (tons) - 14.9 tons (short) per year
(0.017 lb/MMBtu/h x 199.9 MMBtu/h x 24 hours/day x 365 days/year)/2000

Best Regards,
Sara

Sara E. Cosper, PE, P.Eng.
Process-Technip USA, Inc.
555 West Arrow Highway
Claremont, CA 91711
Direct: (909) 447-3732
Fax: (909) 447-3708

----- Forwarded by Vinay Khurana/AMERICA on 03/13/2013 12:54 PM -----

From:	"Leigh, Donald R" <DLeigh@Frontieroil-eld.com>
To:	'Vinay Khurana' <VKhurana@technip.com>, "Hittle, Kane E." <KHittle@Frontieroil-eld.com>,
Date:	03/13/2013 08:24 AM
Subject:	RE: H2 Plant Bid

Vinay-
I need the fired duty for the reformer, tons of NOx per year, tons of CO per year?
Can you show the calculations for the NOx and CO?

I am working with environmental permitting.

Don Leigh

Attachment 5

Updated Table B-6 - GHG Emission Calculations

Table B-6
Potential HAP and CO_2e Emission Calculations for Combustion Units
Frontier El Dorado Refinery

Unit		HGU-3	Emission Totals
Source Name		HGU3 Reformer Furnace (new)	
Potential Firing Rate (MMBtu/hr)		210	
Pollutant	Emission Factor[1]	Emissions (lbs/yr)	(TPY)
Organic HAP			
2-Methylnaphthalene	2.4E-05	0.04	0.00
3-Methychloranthrene	1.8E-06	0.00	0.00
7,12-Dimethylbenz(a)anthracene	1.6E-05	0.03	0.00
Acenaphthene	1.8E-06	0.00	0.00
Acenaphthylene	1.8E-06	0.00	0.00
Anthracene	2.4E-06	0.00	0.00
Benz(a)anthracene	1.8E-06	0.00	0.00
Benzene	2.1E-03	3.79	0.00
Benzo(a)pyrene	1.2E-06	0.00	0.00
Benzo(b)fluoranthene	1.8E-06	0.00	0.00
Benzo(g,h,i)perylene	1.2E-06	0.00	0.00
Benzo(k)fluoranthene	1.8E-06	0.00	0.00
Chrysene	1.8E-06	0.00	0.00
Dibenzo(a,h)anthracene	1.2E-06	0.00	0.00
Dichlorobenzene	1.2E-03	2.16	0.00
Fluoranthene	3.0E-06	0.01	0.00
Fluorene	2.8E-06	0.01	0.00
Formaldehyde	7.5E-02	135.26	0.07
Hexane	1.8E+00	3246.35	1.62
Indeo(1,2,3-cd)pyrene	1.8E-06	0.00	0.00
Naphthalene	6.1E-04	1.10	0.00
Phenanthrene	1.7E-05	0.03	0.00
Pyrene	5.0E-06	0.01	0.00
Toluene	3.4E-03	6.13	0.00
Metal HAP			
Arsenic	2.0E-04	0.36	0.00
Barium	4.4E-03	7.94	0.00
Beryllium	1.2E-05	0.02	0.00
Cadmium	1.1E-03	1.98	0.00
Chromium	1.4E-03	2.52	0.00
Cobalt	8.4E-05	0.15	0.00
Copper	8.5E-04	1.53	0.00
Manganese	3.8E-04	0.69	0.00
Mercury	2.6E-04	0.47	0.00
Molybdenum	1.1E-03	1.98	0.00
Nickel	2.1E-03	3.79	0.00
Selenium	2.4E-05	0.04	0.00
Vanadium	2.3E-03	4.15	0.00
Zinc	2.9E-02	52.30	0.03
Total HAP[3]	-	3,472.89	1.74

Fuel Flow (scf/yr)		1,803,529,411.76	
Annual Average Carbon Content (kg C/kg fuel)		0.85	
Annual Average Molecular Weight (kg/kg-mol)		23.64	
Molar Volume Conversion Factor (@ 68° F)		849.50	
HHV (mmBtu/scf)		0.0010	
GHG - CO_2	-	345,374,389	172,687
GHG - N_2O (kg/MMBtu)	1.0E-03	4,056.32	2.03
GHG - CH_4 (kg/MMBtu)	1.0E-04	405.63	0.20
Total CO_2e[4]	-		173,320.28

Notes

[1] Emission Factors in units of (lb/10^6 scf); from AP-42 Table 1.4-3 for Organic HAPs, and Table 1.4-4 for Metal HAPs, dated 7/98.

[2] GHG emissions are calculated based on Eq. C-5 for CO_2 and Eq. C-8 for CH_4 and N_2O in 40 CFR §98.33

[3] Total Hazardous Air Pollutants (HAPs)

[4] Fuel carbon content, molecular weight and heat content with contingency were used to calculate GHG emissions.

Attachment 6
EPA Guidance on Using SOCMI Factors

EPA United States Environmental Protection Agency

Office of Pollution Prevention and Toxics Washington, DC 20460

December 1998
EPA 745-B-98-004

EPCRA Section 313 Questions and Answers

Revised 1998 Version

Q&A

Section 313 of the Emergency Planning and Community Right-to-Know Act

Toxic Chemical Release Inventory

RELEASE/WASTE MANAGEMENT

"E" is used only for published emission factors which are chemical specific. However, in this case, the company would use "O" which is used if it measured leaks generally or applied non-published factors developed at other *facilities*.

Releases, Basis of Estimate

499. If total *releases* are obtained using a combination of estimating techniques, how do we report "Basis of Estimate" in Section 5, Column B?

Report the basis of estimate code associated with the technique used to calculate the major portion of each *release* entry. See examples in the current Form R instructions.

Releases, Emission Factors

500. Are SOCMI (Synthetic Organic Chemicals Manufacturing Industry) emission factors applicable to the petroleum refining industry as well as to organic chemical manufacturers?

Yes, SOCMI fugitive emission factors can be used for the petroleum refining industry even though they are based upon synthetic organic chemicals manufacturing. The refinery user would have to correct for differences in concentrations of the *mixtures*, because SOCMI factors are based upon pure substances being *released*.

Basis of Estimate, Emission Factors

501. Are emission factors published by other than EPA sources reported as an "E" or an "O"?

Published emission factors by sources other than EPA that contain chemical specific emission rates may be reported as "E". Published emission factors that are not chemical specific are indicated as "O".

Releases, Basis of Estimate, Emission Factors

502. EPA's fugitive emission factors for equipment leaks for the Synthetic Organic Chemicals Manufacturing Industry (SOCMI) and some air emission factors listed in EPA's document *AP-42*, Compilation of Air Pollutant Emission Factors, are not chemical specific. Should the basis of estimate code be entered as "E" or "O"?

Use "O" for non-chemical-specific emission factors.

Estimating Releases, Section 8

503. A *covered facility* has estimated fugitive emissions to be 52 pounds and, based on their lack of precision in this estimate, have reported it as range code B (11–499 pounds) in Section 5 of the Form R. When reporting the quantity *released* in Section 8.1, what quantity should they use to represent their fugitive emissions when adding up all *releases*: 52 (the calculated result) or 255 (the midpoint of the range)?

The air emissions reported in Section 8.1 should be 52 pounds unless the *facility* has better information about their emissions. *Facilities* are not

Attachment 7
VOC Content in HGU-3 Piping Components

HGU-3 Average VOC Content Calculations

Component Type	Valves	Valves	Valves	Pump Seals	Pump Seals	Comp. Seals	Rel. Valves	Flanges	Open-End	Sampling	Process	VOC Content
Service Type	Gas	Lt. Liq.	Hvy. Liq.	Lt. Liq.	Hvy. Liq.	Gas/Vap.	Gas/Vap.	All	Lines, All	Con., All	Drains	wt%
SOCMI Factors (lb/hr/component)	0.00029	0.00036	0.00051	0.0041	0.0046	0.1971	0.0986	0.00018	0.0033	0.033	0.00013	-
Total Component Count	98	0	0	0	0	0	4	226	0	0	0	-
Plant Fuel Gas Component Count	77	0	0	0	0	0	2	166	0	0	0	13
Ammonia Component Count	21	0	0	0	0	0	2	60	0	0	0	0

Component Type	Valves	Valves	Valves	Pump Seals	Pump Seals	Comp. Seals	Rel. Valves	Flanges	Open-End	Sampling	Process	Emissions	VOC Emissions
Service Type	Gas	Lt. Liq.	Hvy. Liq.	Lt. Liq.	Hvy. Liq.	Gas/Vap.	Gas/Vap.	All	Lines, All	Con., All	Drains	(lb/hr)	(lb/hr)
Plant Fuel Gas	0.022	0	0	0	0	0	0.1971	0.0296	0	0	0	0.25	0.03
Ammonia	0.006	0	0	0	0	0	0.1971	0.0107	0	0	0	0.21	0.00
											Total	0.46	0.03
											Average VOC Content (Total VOC Emissions/Total Emissions)	--	7.0%

Attachment 8
Detailed Calculations for HGU-3 Atmospheric Vents

Table B-13
HGU-3: Potential Atmospheric Vent Emission Calculations
Frontier El Dorado Refinery

Stream	Mass Flow Rate	Methanol Composition	Ammonia Composition	Methanol Emissions		Ammonia Emissions	
	(lb/hr)	(ppmw)	(ppmw)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Steam Superheat Coil	105,575.43	51	26	5.38	0.065	2.74	0.033
Degasifier	1,417.71	52	27	0.07	0.32	0.04	0.17
Blowdown Drum (Intermittent Blowdown)	20.00	7.3	2.8	1.22E-06	4.44E-07	4.67E-07	1.70E-07
Blowdown Drum (Degasifier down)	717.71	7.3	2.8	0.01	1.26E-04	2.01E-03	4.82E-05
Total				**5.46**	**0.39**	**2.79**	**0.20**

Notes:
1) The Steam Superheat Coil vents 12/hrs per cold startup and there are 2 cold startups/year
2) The Degasifier vent continuously
3) The Blowdown Drum (Intermittent Blowdown) vents for 30 seconds, once per shift, with 2 shifts per day
4) The Blowdown Drum (Degasifier down) vents 2 days per year

Detailed Calculations for HGU-3 Atmospheric Vents

Steam Superheat Coil - Methanol Emission Calculations

$$\frac{105{,}575.43\ \text{lb}}{\text{hr}} \times \frac{51}{1{,}000{,}000} = \frac{5.38\ \text{lb}}{\text{hr}}$$

$$\frac{5.38\ \text{lb}}{\text{hr}} \times \frac{12\ \text{hrs}}{\text{startup}} \times \frac{2\ \text{startup}}{\text{yr}} \times \frac{\text{ton}}{2000\ \text{lb}} = \frac{0.065\ \text{ton}}{\text{yr}}$$

Steam Superheat Coil - Ammonia Emission Calculations

$$\frac{105{,}575.43\ \text{lb}}{\text{hr}} \times \frac{26}{1{,}000{,}000} = \frac{2.74\ \text{lb}}{\text{hr}}$$

$$\frac{2.74\ \text{lb}}{\text{hr}} \times \frac{12\ \text{hrs}}{\text{startup}} \times \frac{2\ \text{startup}}{\text{yr}} \times \frac{\text{ton}}{2000\ \text{lb}} = \frac{0.033\ \text{ton}}{\text{yr}}$$

Degasifier - Methanol Emission Calculations

$$\frac{1{,}417.71\ \text{lb}}{\text{hr}} \times \frac{52}{1{,}000{,}000} = \frac{0.07\ \text{lb}}{\text{hr}}$$

$$\frac{0.07\ \text{lb}}{\text{hr}} \times \frac{8760\ \text{hrs}}{\text{yr}} \times \frac{\text{ton}}{2000\ \text{lb}} = \frac{0.32\ \text{ton}}{\text{yr}}$$

Degasifier - Ammonia Emission Calculations

$$\frac{1{,}417.71\ \text{lb}}{\text{hr}} \times \frac{27}{1{,}000{,}000} = \frac{0.04\ \text{lb}}{\text{hr}}$$

$$\frac{0.04\ \text{lb}}{\text{hr}} \times \frac{8760\ \text{hrs}}{\text{startup}} \times \frac{\text{ton}}{2000\ \text{lb}} = \frac{0.17\ \text{ton}}{\text{yr}}$$

Blowdown Drum (Intermittent) - Methanol Emission Calculations

$$\frac{20.00\ \text{lb}}{\text{hr}} \times \frac{7.3}{1{,}000{,}000} \times \frac{30\ \text{sec}}{\text{hr}} \times \frac{\text{hr}}{3{,}600\ \text{sec}} = \frac{1.22\text{E-}06\ \text{lb}}{\text{hr}}$$

$$\frac{1.22\text{E-}06\ \text{lb}}{\text{hr}} \times \frac{2\ \text{shifts}}{\text{day}} \times \frac{365\ \text{days}}{\text{yr}} \times \frac{\text{ton}}{2000\ \text{lb}} = \frac{4.44\text{E-}07\ \text{ton}}{\text{yr}}$$

Blowdown Drum (Intermittent) - Ammonia Emission Calculations

$$\frac{20.00\ \text{lb}}{\text{hr}} \times \frac{2.8}{1{,}000{,}000} \times \frac{30\ \text{sec}}{\text{hr}} \times \frac{\text{hr}}{3{,}600\ \text{sec}} = \frac{4.67\text{E-}07\ \text{lb}}{\text{hr}}$$

$$\frac{4.67\text{E-}07\ \text{lb}}{\text{hr}} \times \frac{2\ \text{shifts}}{\text{day}} \times \frac{365\ \text{days}}{\text{yr}} \times \frac{\text{ton}}{2000\ \text{lb}} = \frac{1.70\text{E-}07\ \text{ton}}{\text{yr}}$$

Blowdown Drum (Degasifier Down) - Methanol Emission Calculations

$$\frac{717.71\ \text{lb}}{\text{hr}} \times \frac{7.3}{1{,}000{,}000} = \frac{0.01\ \text{lb}}{\text{hr}}$$

$$\frac{0.01\ \text{lb}}{\text{hr}} \times \frac{24\ \text{hrs}}{\text{day}} \times \frac{2\ \text{days}}{\text{yr}} \times \frac{\text{ton}}{2000\ \text{lb}} = \frac{1.26\text{E-}04\ \text{ton}}{\text{yr}}$$

Blowdown Drum (Degasifier Down) - Ammonia Emission Calculations

$$\frac{717.71\ \text{lb}}{\text{hr}} \times \frac{2.8}{1{,}000{,}000} = \frac{2.01\text{E-}03\ \text{lb}}{\text{hr}}$$

$$\frac{2.01\text{E-}03\ \text{lb}}{\text{hr}} \times \frac{24\ \text{hrs}}{\text{day}} \times \frac{2\ \text{days}}{\text{yr}} \times \frac{\text{ton}}{2000\ \text{lb}} = \frac{4.82\text{E-}05\ \text{ton}}{\text{yr}}$$